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SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS
HAWTHORN STATION, KANSAS CITY POWER AND LIGHT COMPANY

Gerald A. Isaacs, et al

PEDCo-Environmental, Incorporated

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National Environmental Research Center

September 1975

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16. ABSTRACT The report gives results of a survey of the flue gas desulfurization (FGD) systems at Kansas City Power and Light Co.'s Hawthorn Power Station. The FGD systems on Hawthorn boilers 3 and 4 were designed to operate by injection of dry limestone in the boiler's furnace, followed by tail gas scrubbing. Because of tube plugging in boiler 4, the mode of operation of the FGD system on that boiler was modified: ground limestone is now introduced into the flue gas near the gas inlet to the scrubber tower. The FGD system on boiler 3 continues to operate as originally designed. Both systems, however, have undergone minor modifications to overcome such difficulties as buildup of sediment and plugging of various components. The FGD system on each boiler consists of two identical modules, each capable of treating 500,000 acfm of flue gas at 300F. Particulate and SO ₂ removal efficiencies for the FGD systems, placed in operation in 1972, are 99 and 70 percent, respectively. Considerable capital investment associated with the FGD systems was underwritten by the vendor so that KCP and L's investment was only about \$5.6 million (about \$19/KW). The annualized operating cost is reported to range between 2.2 and 2.5 mills/KWH.			
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by

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Mr. Wade H. Ponder, former EPA Project Officer, had primary responsibility within EPA for this project report. Information and data on plant operation were provided by Mr. Charles Trask, Kansas City Power and Light Company, and by Mr. Peter Maurin, Combustion Engineering, Inc., during and subsequent to the survey visit. Mr. Charles D. Fleming was responsible for editorial review of this report.

The authors appreciate the efforts and cooperation of everyone who participated in the preparation of this report.

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SUMMARY

The dry limestone flue gas desulfurization (FGD) systems on Boilers No. 3 and 4 at the Hawthorn Power Station of Kansas City Power and Light Company (KCP&L) were designed and installed by Combustion Engineering, Inc. (C-E). Initially, both systems were designed to operate by injection of dry limestone in the boiler's furnace, followed by tail gas scrubbing of both the SO_2 and the furnace-calcined limestone (as well as the fly ash) from the flue gas stream. Because of tube plugging in Boiler No. 4, attributed to limestone injection, the mode of operation of this FGD system was modified. Ground limestone is no longer injected into the furnace but instead is introduced into the flue gas near the gas inlet to the tail scrubber tower. The FGD system on Boiler No. 3 continues to operate as originally designed. Both systems, however, have undergone numerous modifications to attempt to overcome such difficulties as buildup of sediment and plugging of various components.

The FGD system on each boiler consists of two identical modules, each capable of treating 500,000 acfm of flue gas at 300°F. Bypassing of the modules is possible through a system of ductwork and dampers around each module. Water-

filled seals are provided in the bypass lines to prevent gas leakage during normal operation.

The FGD system on Boiler No. 4 was placed in operation in August 1972; the system of Boiler No. 3 was started in November 1972. Removal efficiencies for particulate and sulfur dioxide were 99 percent and 70 percent, respectively.

The plant has no limestone grinding facilities as such. Limestone is ground in the coal pulverizers of Boilers 1 and 2 on an intermittent basis.

The spent limestone slurry from all modules is discharged into a common clarifier tank, and the underflow is pumped, untreated and unstabilized, to an unlined pond, which is also used for disposal of fly ash from the other boilers.

A considerable portion of the capital investment associated with the FGD systems was underwritten by the vendor so that KCP&L's investment is estimated to be only about \$5.6 million (about \$19/KW). The annualized operating cost is reported to range between 2.2 and 2.5 mills/KWH.

Because of continued operational problems since start-up, the availability factor for the systems has been low (in the range of 30 to 40%). Recent operation of the FGD system on Boilers 3 and 4 has shown improvement, with availability reported at around 50 percent.

Pertinent facility and FGD operational data are summarized in the following table.

SUMMARY OF FGD DATA, BOILERS NO. 3 AND 4,
HAWTHORN POWER STATION

Unit rating	100 MW ^a
Fuel characteristics:	Coal (high ash): 14% ash, 3% S, 11,500 BTU/lb Coal (low ash): 11% ash, 0.6% S, 9,800 BTU/lb
FGD vendor:	Combustion Engineering
Process:	Limestone injection
New or retrofit:	Retrofit
Start-up date:	Boiler No. 3 - August 1972 Boiler No. 4 - November 1972
FGD modules:	Two per boiler
Efficiency, %	
Particulates	99
SO ₂	70
Make-up water:	8 gpm/MW
Sludge disposal:	Unstabilized sludge disposed in unlined pond
Unit cost:	KCP&L capital investments approximately \$19/KW; in addition to considerable capital expenditures by vendor; operating cost approximately 2.5 mills/KWH.

^a When burning coal. The maximum boiler generating capacity when burning natural gas is 140 MW.

1.0 INTRODUCTION

The Industrial Environmental Research Laboratory (formerly the Control Systems Laboratory) of the U.S. Environmental Protection Agency (EPA) has initiated a study to evaluate the performance characteristics and degree of reliability of flue gas desulfurization (FGD) systems on coal-fired utility boilers in the United States. This report on the Hawthorn Power Station of Kansas City Power and Light Company (KCP&L) is one of a series of reports on such systems. It presents values of key process design and operating parameters, describes the major start-up and operational problems encountered at the facility and the measures taken to alleviate such problems, and identifies the total installed and annualized operating costs.

This report is based upon information obtained during a plant inspection on June 6, 1974, and on data provided by KCP&L and Combustion Engineering, Inc. personnel.

Section 2.0 presents pertinent data on facility design and operation, including actual and allowable particulate and SO₂ emission rates. Section 3.0 describes the FGD system, and Section 4.0 analyzes FGD system performance. Appendices present details of plant and system operation and photos of the installation.

2.0 FACILITY DESCRIPTION

The Hawthorn Power Station of KCP&L is located in a heavily industrialized area on the north bank of the Missouri River in East Kansas City, Missouri.

The plant operates five coal-fired boilers. Boilers 1 and 2 are considered peak boilers, each rated at 80 MW. Boilers 3 and 4 are cyclic boilers, rated at 100 MW each, when burning coal. These four boilers were built and placed in service between 1950 and 1955. Boiler 5 was placed in service in early 1970; it operates as a base-load boiler at a rated capacity of 500 MW.

The boilers at the Hawthorn Power Station are all dry-bottom, pulverized-coal-fired units designed and manufactured by Combustion Engineering, which also manufactured the FGD systems for this plant.

Two grades of coal are burned: the higher-ash content coal typically contains 14 percent ash and 3 percent sulfur, with a heat content of 11,400 BTU/lb; the lower-ash content coal has 11 percent ash, 0.6 percent sulfur, and a heat content of 9800 BTU/lb.

Of the five boilers at the Hawthorn Power Station, only Boilers 3 and 4 are fitted with FGD systems. Originally both FGD systems operated by furnace injection of ground

limestone rock followed by a flue gas wet-scrubbing system in which both the SO_2 and the furnace-calcined limestone were scrubbed and allowed to react in a reaction tank. This system is still used on Boiler 3; the system on Boiler 4 has since been converted to tail-end injection, in which the ground limestone is injected into the gas duct between the air heater and the scrubber vessel.

The maximum particulate emission allowed under Regulation III of the Missouri Air Conservation Commission is 0.19 lb/MM BTU of heat input to the boiler. The present atmospheric emission of particulate from the Hawthorn FGD systems is equivalent to 0.11 lb/MM BTU.

Atmospheric emissions of sulfur dioxide are limited by Regulation XV of the Missouri Air Conservation Commission. However, this plant is not in a critical area, so SO_2 removal is not required by that regulation.

Table 2.1 presents pertinent data on plant design, FGD system operation, and atmospheric emissions.

Table 2.1 PERTINENT DATA ON PLANT DESIGN,
OPERATION AND ATMOSPHERIC EMISSIONS

Boiler data	Unit 3	Unit 4
Rated generating capacity, MW	100 ^a	100 ^a
Average capacity factor, 1974	44.5	47.1
Served by stack number	1	1
Boiler manufacturer	C-E	C-E
Year placed in service	1953	1953
Maximum coal consumption, ton/hr	50 ^b	50 ^b
Maximum heat input, MM BTU/hr	1,000 ^b	1,000 ^b
Stack height above grade, ft.	200	200
Flue gas rate - maximum, acfm	500,000	500,000
Flue gas temperature, °F	300	300
Emission controls,		
Particulate	Absorber tower	Absorber tower
SO ₂	Absorber tower	Absorber tower
Particulate emission rate,		
Allowable, lb/MM BTU	0.21	0.21
Actual, lb/MM BTU	0.11 ^b	0.11 ^b
SO ₂ emission rate,		
Allowable, lb/MM BTU	ambient air standards only	
Actual, lb/MM BTU	0.18	0.18

^a When burning coal. Maximum boiler output when burning natural gas is 140 MW.

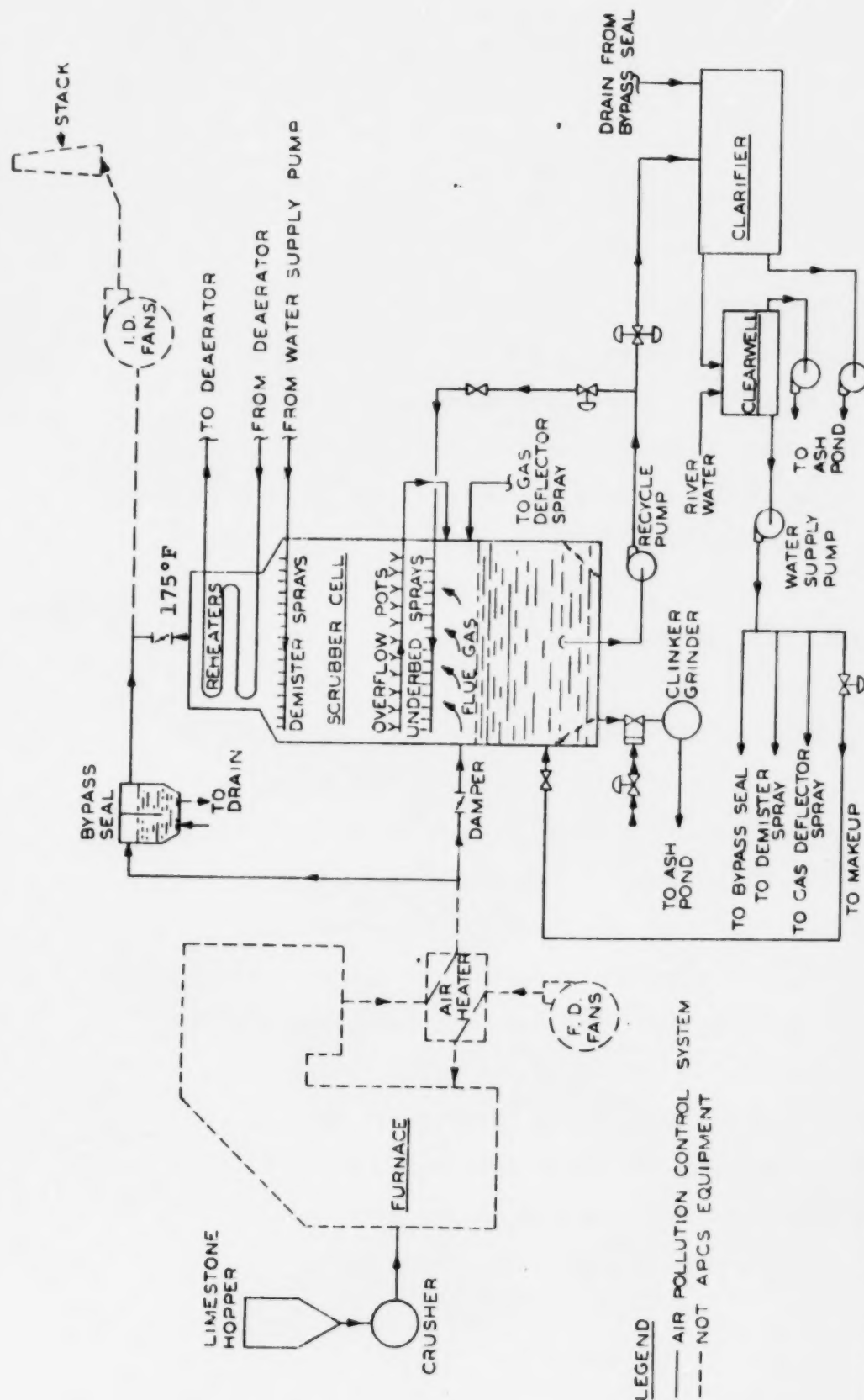
^b Calculated value.

3.0 FLUE GAS DESULFURIZATION SYSTEMS

3.1 PROCESS DESCRIPTION

The FGD systems on Boilers 3 and 4 are identical in basic design, the primary difference being the point of limestone injection. As mentioned earlier, dry limestone is injected directly in the furnace of Boiler 3 and is calcined to lime. The scrubbing reagent, therefore, is lime and not limestone. In the system on Boiler 4, the dry limestone is injected in the flue gas duct near the inlet to the SO₂ absorber tower.

Two parallel scrubber modules (or trains) are connected to each boiler. Details of a typical module are shown in Figures 3.1 and 3.2. Each scrubber module is 18 feet wide, 26 feet long, and 56 feet high. The lower 16 feet of the module is the reaction tank, in which the materials have time to complete their chemical reactions to remove sulfur. To provide thorough mixing and to keep the reactants and the fly ash in suspension, one mixer is installed on the lower back wall and a second mixer on the upper front wall of the reaction tank. Plans are now being made for the addition of one mixer per module to be installed on the side walls to further increase agitation in the tank.



(Courtesy - Kansas City Power and Light Co.)

Figure 3.1 Process flow diagram of a typical FGD module, similar to those used on Boilers 3 and 4.

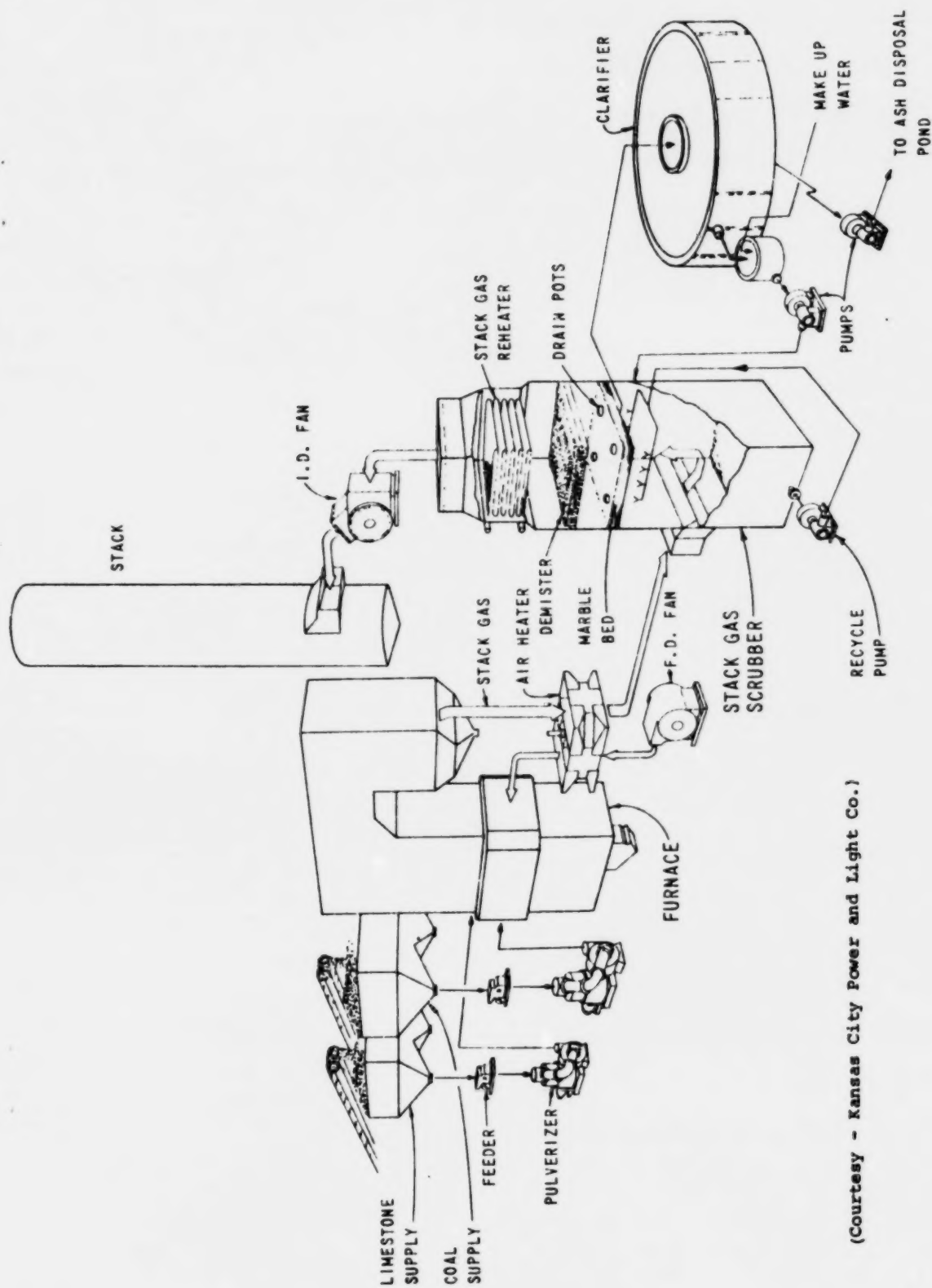


Figure 3.2 Sketch of a dry limestone furnace injection process with a tail-end scrubbing FGD system.

A sloping, perforated plate near the top of the reaction tanks acts as a strainer to catch large solid objects, such as scale, mud, or marbles, and funnels them to the mouth of a jaw crusher. Periodic operation of this equipment reduces these pieces to fine particles, which are slurried and discharged to the fly ash pond.

As the flue gas enters the absorber tower above the liquid level in the reaction tank, it comes in contact with slurry, which is sprayed through 63 nozzles on 14 headers located under the marble bed. The marble bed consists of a 3- to 4-inch thickness of 3/4-inch-diameter glass marbles. The marbles are retained on a perforated plate through which the quenched flue gas and the sprayed slurry bubble giving the marbles a spinning motion. These marbles provide an increased surface area to facilitate contact of the reactants. The liquid level above the marble bed is 10 to 13 inches high. The liquid overflow from the bed is discharged through 66 drain pots. The scrubbed flue gases flow upward 10 feet to a double row of chevron separators designed to remove any water droplets carried by the flue gases. The gases then pass around horizontal fin-tubed heaters that reheat the gases to about 175°F before they are discharged to the stack by the induced-draft fans. Gases from all modules on Boilers 3 and 4 are discharged to the atmosphere through a common stack 200 feet high.

Limestone for Boilers 3 and 4 is ground intermittently in the coal pulverizers of Boilers 1 and 2 respectively, during the periods when these peak-load boilers are not in service.

Spent liquor from the reaction tank of each module is discharged to a 115-foot-diameter clarifier tank. The overflow from this tank flows to a clear well tank, where make-up water from the Missouri River is added. The discharge from this tank satisfies the water requirements of the FGD system. Distribution of the water is shown in Figure 3.1.

Sludge in the underflow from the clarifier tank is untreated. The thickened sludge is pumped to a 160-acre pond, which is also used for disposal of fly ash from the other boilers.

Inlet and outlet dampers are provided on each scrubber module to divert the gases either through or around the module. To ensure passage of gases through the scrubber when it is in operation, a large U-shaped bypass seal is filled with water to positively close the bypass.

The demister wash system uses a set of eight water lances, four located above and four below the demister vanes. These lances automatically wash mud from the demisters whenever the dampers close.

Stack gas is reheated by a fin-tube heat exchanger utilizing hot water from the suction of the boiler feed

pumps as a heat source. The water enters the heat exchanger at 150 psig and 325°F. The reheater tubes are cleaned by two steam lances located beneath the heat exchanger.

3.2 DESIGN PARAMETERS

The two FGD installations at the Hawthorn Power Station were designed by Combustion Engineering to treat a total of about 1,000,000 acfm of flue gas at 300°F. Before the scrubbers were installed, mechanical precipitators were used to remove fly ash. Pressure drop across these precipitators was about 7 inches; this also is the design figure for the scrubber modules, a value that has never been attained. Pressure drop across the scrubber module is 10 to 12 inches of water.

The scrubber tower operates with a liquid-to-gas ratio of about 21 gal./1000 ft³ of gas at 122°F. Modifications of the recirculation system have increased this figure to 26 gal./1000 ft³. Superficial velocity through the demister section of the tower is about 10 ft/sec.

Tables 3.1, 3.2, and 3.3 summarize operating design parameters and specifications for major components of the FGD system.

3.3 INSTALLATION SCHEDULE

The installation of the FGD systems at the Hawthorn Power Station did not proceed according to the pattern for typical construction projects. The installation was highly experimental, and the vendor was willing to underwrite a

Table 3.1 SUMMARY OF DATA: FGD SCRUBBER TOWER

	FGD Scrubber Tower
L/G ratio, gal/1000 acf	26
Superficial gas velocity, ft/sec	10 (design)
Equipment sizes	18 x 26 ft x 40 ft high
Equipment internals	3.5" thick bed of 3/4" dia. marbles
Material of construction	
Shell	Carbon steel (Ceilcote)
Internal supports	316L SS

Table 3.2 SUMMARY OF DATA: FGD SYSTEM HOLD TANKS

	SO ₂ Scrubber Towers Holdup Tank	FGD System Clarifier Tank
Total number of tanks	One/module	One
Tank size	18' x 26' x 16' high	115'dia x 10'
Retention time at full load	11 min.	4.5 hr
Temperature, °F	122	110
pH	5.0 to 5.5	5.2
Solids concentration, %	10 - 15	
Specific gravity	-	-
Material of construction	Carbon steel	

Table 3.3 SUMMARY OF DATA: FGD SYSTEM PRESSURE DROP

Equipment	Pressure drop, inches W.G.
SO ₂ scrubber tower	8 - 9.5
Demister	1 - 1.5
Reheater	1 - 1.5
Ductwork	1 - 2
Total FGD system	12 - 13

considerable portion of the project. Consequently, C-E was chosen in advance as the FGD vendor. Therefore, bid specifications on the FGD systems were not prepared by KCP&L, and bids were not requested from competing vendors. System start-up occurred for Unit No. 4 in August 1972 and for Unit No. 3 in November 1972. Late in 1972, severe limestone plugging of the top horizontal tubes of Boiler No. 4 was discovered and the decision was made to convert the FGD system on this boiler to a tail-end limestone injection system. Similar plugging has not been observed on Boiler No. 3, and the FGD unit continues to operate in the original design mode.

3.4 COST DATA

Detailed data on the capital and operating costs of the FGD installations at the Hawthorn Power Station are not available. The capital investment cost is reported to be about \$5.32 million (about \$19/KW of the gross generating capacity). This figure is unrealistically low because this installation is experimental in nature and was heavily underwritten by the vendor. This figure accounts for the FGD systems on both boilers. Operating costs range between 2.2 and 2.5 mills/KWH.

4.0 FGD SYSTEM PERFORMANCE ANALYSIS

4.1 GENERAL DISCUSSION

Modifications were completed by Combustion Engineering in June 1974, and KCP&L has continued to modify the modules in an effort to improve the operation of the FGD systems. Module in-service hours in 1975, through May, totaled 1334. For the same period last year the total was 816 hours. Continuous monitoring equipment when operational has shown sulfur removal efficiency in the range of 85 to 95 percent. Particulate removal efficiency was 98 to 99 percent.

FGD system availability has been consistently low, mainly due to the bypass seal configuration. The bypass water seal accumulates flyash when it is opened so that it cannot be closed again without shutting down the boiler and manually cleaning the bypass section. Thus, the FGD system remains "unavailable" until it is convenient to shut down the boiler. New dampers have been designed and ordered. They will be installed around mid-1976 to correct this problem. It is anticipated that this modification will increase the FGD system availability significantly.

4.2 START-UP PROBLEMS AND SOLUTIONS

Analysis of the problems encountered during and since start-up, reveals that nearly all were due to mechanical design rather than process chemistry.

Apart from those entailed in switching Unit No. 4 from furnace injection to tail gas injection, the major problems encountered with the two FGD systems at the Hawthorn Power Station have been identical.

1. Sediment Buildup: The reaction tank of each module is equipped with two mixers to keep the 10 percent solids in suspension. A third mixer will be installed to increase agitation. The original 15-hp mixers were not adequate; a buildup of hard mud, 6 to 8 feet high, developed in the corners of the reaction tank. Replacement of the original mixers with 25-hp units gave no significant improvement. The most recent modification to eliminate sediment buildup consists of rounding off the bottom corners of the tanks by welding triangular steel plates, as shown in Figure 4.1. Further, a new make-up water piping system was installed, with four 1-inch nozzles located on the walls about 6 feet from the base of the tank and oriented to promote circulation and prevent settling of solids.

2. Plugging of the Marble Bed: In the initial construction, the drain pots drained into horizontal headers that penetrated the module walls and emptied into the reaction tank. These horizontal headers plugged soon after the system was placed in operation. The headers were removed, and sloping headers were placed inside the reaction tank. These modified headers improved the situation but did not completely solve the problem. An additional problem

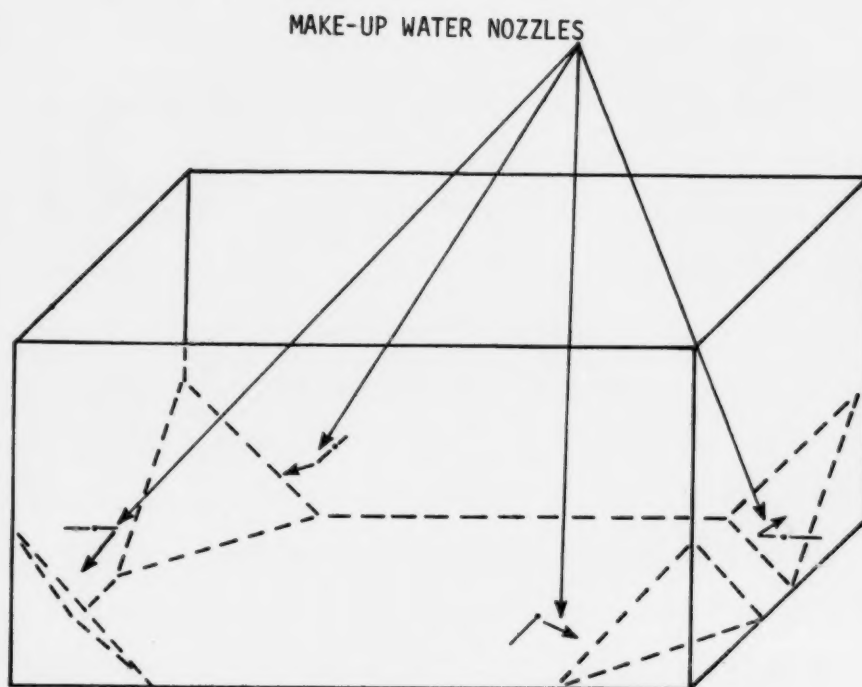


Figure 4.1 Sketch of the reaction tank showing the rounding off of the tank's corners and the installation of make-up water, sediment flushing system.

occurred frequently when drain pots lifted off the marble bed and allowed marbles to fall into the reaction tank. Both of these problems have been solved by installation of new stainless steel drain pots with expanded metal covers; a 3-foot rubber sock allows each pot to drain directly into the reaction tank. The pots are attached to stainless steel rods welded to the marble bed support. The covers are fastened to the pots. Only limited plugging of the new drain pots has occurred.

Plugging in the marble bed has been reduced by an operational change. Increasing the liquid-to-gas ratio from 21 to 26 gal./1000 ft³ at 125°F has increased the flow of liquid sufficiently to ensure that all parts of the marble bed are washed by at least two nozzles.

3. Excessive Wear of Spray Nozzles: The spray nozzle orifices were severely worn by the abrasive action of the fly ash. The initial nozzles lasted only a few days; these had to be replaced because the enlarged orifices caused buildup of mud in the marble bed, overloading of the recycle pump and clogging of the demister. Although KCP&L installed a series of nozzles of different materials from different vendors, the longest life obtained from any of those was about 3 weeks. Since these nozzles are very expensive, KCP&L designed a nozzle that could be made in the shop from pipe parts. These nozzles lasted about 3 weeks, but their cost was only 5 to 10 percent of the cost of

vendors' nozzles. Finally, ceramic nozzles were installed, and they have exhibited no signs of wear after nearly a year of operation. This is by far the best performance experienced to date, since all other nozzles were completely worn within one to three weeks.

4. Demister Plugging: During sustained operations the scrubber modules must be taken out of service every three days to firehose mud from the demisters. Plugging has been controlled somewhat by adding retractable water lance blowers under the demister and by moving the rotary water lance blowers from below the demister to between the rows of demister vanes. Manual washing is still necessary once or twice each week.

5. Bypass Seal Plugging: As mentioned earlier, when the flue gas is bypassed around the module, the empty water seal acts as a mechanical dust collector, accumulating fly ash. When the module is returned to operation and water is turned on, the wet fly ash hampers the operation of the bypass seal. Plugging in this seal has not been eliminated by changing the flushing sequence within the seal. Plugging occurs during module operations and almost always requires a one to two-day unit outage for cleaning. Plans are presently underway to remove the wet bypass seal altogether and to install a drawbridge-type damper in hopes of solving this, the biggest of current operating problems.

APPENDIX A

PLANT SURVEY FORMS

UNIT NO. 3

PLANT SURVEY FORM

NON-REGENERABLE FGD PROCESSES

A. COMPANY AND PLANT INFORMATION

1.	COMPANY NAME	<u>Kansas City Power & Light</u>
2.	MAIN OFFICE	<u>Kansas City, Mo.</u>
3.	OPERATING SUPERINTENDENT	<u>Vern Moore</u>
4.	PLANT NAME	<u>Hawthorn Plant</u>
5.	PLANT LOCATION	<u>Kansas City</u>
6.	PERSON TO CONTACT FOR FURTHER INFORMATION	<u>Terry Eaton</u>
7.	POSITION	<u>Results Superintendent</u>
8.	TELEPHONE NUMBER	<u>471-0060 (816)</u>
9.	DATE INFORMATION GATHERED	<u>6/6/74</u>
10.	PARTICIPANTS IN MEETING	<u>AFFILIATION</u>
	<u>Jerry Bennett</u>	<u>KCPL</u>
	<u>Vince Palerma</u>	<u>KCPL (Part Time)</u>
	<u>Vern Moore</u>	<u>KCPL</u>
	<u>Wade Ponder</u>	<u>EPA</u>
	<u>John Busik</u>	<u>EPA</u>
	<u>Fouad K. Zada</u>	<u>PEDCo-Environmental</u>
	<u>Larry V. Yerino</u>	<u>PEDCo-Environmental</u>

B. PLANT DATA. (APPLIES TO ALL BOILERS AT THE PLANT).

	BOILER NO.				
	1	2	3	4	5
CAPACITY, MW	100	100	140*	140*	500
SERVICE (BASE, PEAK)	Peak	Peak	Cyclic 25-100%	Cyclic 25-100%	Base 50-100%
FGD SYSTEM USED			x	x	

C. BOILER DATA. COMPLETE SECTIONS (C) THROUGH (R) FOR EACH BOILER HAVING AN FGD SYSTEM.

1. BOILER IDENTIFICATION NO. 3
2. MAXIMUM CONTINUOUS HEAT INPUT MM BTU/HR
3. MAXIMUM CONTINUOUS GENERATING CAPACITY 140 MW on N.G.
100 MW on Coal
4. MAXIMUM CONTINUOUS FLUE GAS RATE, 500,000 ACFM @ 300 °F
5. BOILER MANUFACTURER C-E
6. YEAR BOILER PLACED IN SERVICE 1953
7. BOILER SERVICE (BASE LOAD, PEAK, ETC.) Cyclic
8. STACK HEIGHT 200' (common w/4)
9. BOILER OPERATION HOURS/YEAR (1974) 6602
10. BOILER CAPACITY FACTOR ** 44.5
11. RATIO OF FLY ASH/BOTTOM ASH 4/1

* On Natural Gas, (100 MW on Coal)

** DEFINED AS: $\frac{\text{KWH GENERATED IN YEAR}}{\text{MAX. CONT. GENERATED CAPACITY IN KW} \times 8760 \text{ HR/YR}}$

D. FUEL DATA

Low-Ash Hi-Ash
Typical Typical

1. COAL ANALYSIS (as received)

GHV (BTU/LB.)

S %

ASH %

MAX.	MIN.	AVG.
	9800	11400
	0.6	3
	11	14

2. FUEL OIL ANALYSIS (exclude start-up fuel)

GRADE

S %

ASH %

	-	-
	-	-
	-	-

E. ATMOSPHERIC EMISSIONS

1. APPLICABLE EMISSION REGULATIONS

a) CURRENT REQUIREMENTS

AQCR PRIORITY CLASSIFICATION

REGULATION & SECTION NO.

MAX. ALLOWABLE EMISSIONS
LBS/MM BTU

PARTICULATES	SO ₂
0.21 lb/MM BTU	Ambient air standards
Missouri 3	Missouri 15

b) FUTURE REQUIREMENTS,
COMPLIANCE DATE

REGULATION & SECTION NO.

MAXIMUM ALLOWABLE EMISSIONS
LBS/MM BTU

2. PLANT PROGRAM FOR PARTICULATES COMPLIANCE

3. PLANT PROGRAM FOR SO₂ COMPLIANCE

F. PARTICULATE REMOVAL

1. TYPE	MECH.	E.S.P.	FGD
MANUFACTURER			C-E Limestone injection
EFFICIENCY: DESIGN/ACTUAL			> 99%
MAX. EMISSION RATE* LB/HR			
GR/SCF			
LB/MMBTU			

DESIGN BASIS, SULFUR CONTENT _____

G. DESULFURIZATION SYSTEM DATA

1. PROCESS NAME C-E Limestone - furnace injection with tail scrubbing

2. LICENSOR/DESIGNER NAME: Combustion Engineering
 ADDRESS: 7301 Mission Road, Shawnee Mission, Kansas

PERSON TO CONTACT: Ed Ogard or Jim Howard

TELEPHONE NO.: (919) 362-7313

3. ARCHITECTURAL/ENGINEERS, NAME: Black and Veach
 ADDRESS: 1500 Meadow Lake Parkway, Prairie Village, KS.

PERSON TO CONTACT: Lloyd Svoboda

TELEPHONE NO.: (913) 361-7000

4. PROJECT CONSTRUCTION SCHEDULE: DATE

a) DATE OF PREPARATION OF BIDS SPECS. _____

b) DATE OF REQUEST FOR BIDS _____

c) DATE OF CONTRACT AWARD _____

d) DATE ON SITE CONSTRUCTION BEGAN _____

e) DATE ON SITE CONSTRUCTION COMPLETED _____

f) DATE OF INITIAL STARTUP Late Nov. 1972

g) DATE OF COMPLETION OF SHAKEDOWN _____

*At Max. Continuous Capacity

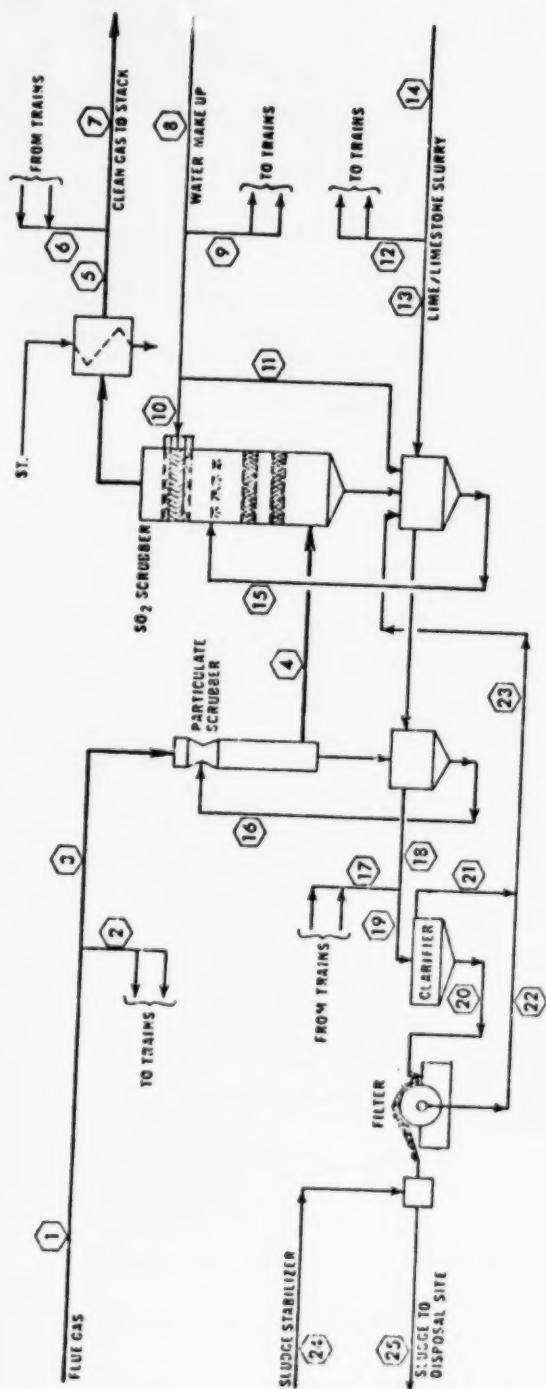
5. LIST MAJOR DELAYS IN CONSTRUCTION SCHEDULE AND CAUSES:

None

6. NUMBER OF SO₂ SCRUBBER TRAINS USED 2
7. DESIGN THROUGHPUT PER TRAIN, ACFM @ °F
8. DRAWINGS: 1) PROCESS FLOW DIAGRAM AND MATERIAL BALANCE
- 2) EQUIPMENT LAYOUT

H. SO₂ SCRUBBING AGENT

1. TYPE Limestone
2. SOURCES OF SUPPLY City Wide Asphalt Co.
3. CHEMICAL COMPOSITION (for each source)
- | | |
|---------------------|---|
| SILICATES | <u> </u> |
| SILICA | <u>1.92%</u> |
| CALCIUM CARBONATE | <u>93.6%</u> |
| MAGNESIUM CARBONATE | <u>1.28%</u> |
4. EXCESS SCRUBBING AGENT USED ABOVE STOICHIOMETRIC REQUIREMENTS
5. MAKE-UP WATER POINT OF ADDITION
6. MAKE-UP ALKALI POINT OF ADDITION



STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13
RATE, lb/hr													
ACFM													
CPM													
PARTICULATES, lb/hr													
SO ₂ , lb/hr													
TEMPERATURE, °F													
TOTAL SOLIDS, %													
SPECIFIC GRAVITY													

STREAM NO	14	15	16	17	18	19	20	21	22	23	24	25	26
RATE, lb/hr													
ACFM													
CPM													
PARTICULATES, lb/hr													
SO ₂ , lb/hr													
TEMPERATURE, °F													
TOTAL SOLIDS, %													
SPECIFIC GRAVITY													

I. Representative flow rates based on operating data at maximum continuous load

J. SCRUBBER TRAIN SPECIFICATIONS

1. SCRUBBER NO. 1 (a) Two identical modules: Specs per module:

TYPE (TOWER/VENTURI) Rectangular Tower (18'x26'x40')

LIQUID/GAS RATIO, G/MCF @ 122 °F 21 to 26

GAS VELOCITY THROUGH SCRUBBER, FT/SEC 10

MATERIAL OF CONSTRUCTION Carbon Steel

TYPE OF LINING Ceilmate

INTERNALS:

TYPE (FLOATING BED, MARBLE BED, ETC.) Marble Bed

NUMBER OF STAGES One

TYPE AND SIZE OF PACKING MATERIAL 3/4"dia. Glass Marble

PACKING THICKNESS PER STAGE (b) 3.5"

MATERIAL OF CONSTRUCTION, PACKING: Glass

SUPPORTS: Stainless Steel 316L

2. SCRUBBER NO. 2 (a)

TYPE (TOWER/VENTURI) _____

LIQUID/GAS RATIO, G/MCF @ °F _____

GAS VELOCITY THROUGH SCRUBBER, FT/SEC _____

MATERIAL OF CONSTRUCTION _____

TYPE OF LINING _____

INTERNALS:

TYPE (FLOATING BED, MARBLE BED, ETC.) _____

NUMBER OF STAGES _____

TYPE AND SIZE OF PACKING MATERIAL _____

a) Scrubber No. 1 is the scrubber that the flue gases first enter. Scrubber 2 (if applicable) follows Scrubber No. 1.

b) For floating bed, packing thickness at rest.

PACKING THICKNESS PER STAGE^(b) _____

MATERIAL OF CONSTRUCTION, PACKING: _____

SUPPORTS: _____

3. CLEAR WATER TRAY (AT TOP OF SCRUBBER)

TYPE _____

L/G RATIO _____

SOURCE OF WATER _____

4. DEMISTER

TYPE (CHEVRON, ETC.) Chevron

NUMBER OF PASSES (STAGES) Two

SPACE BETWEEN VANES 3"

ANGLE OF VANES 45°

TOTAL DEPTH OF DEMISTER 4"each(8" total)

DIAMETER OF DEMISTER 18' x 26'

DISTANCE BETWEEN TOP OF PACKING
AND BOTTOM OF DEMISTER 10'

POSITION (HORIZONTAL, VERTICAL) Horizontal

MATERIAL OF CONSTRUCTION Fiberglass

METHOD OF CLEANING 8 wash lances

SOURCE OF WATER AND PRESSURE Clarified & Make-up Water

FLOW RATE DURING CLEANINGS, GPM _____

FREQUENCY AND DURATION OF CLEANING _____

REMARKS _____

5. REHEATER

TYPE (DIRECT, INDIRECT) Finned Tubes - carbon steel

b) For floating bed, packing thickness at rest.

DUTY, MMBTU/HR _____
 HEAT TRANSFER SURFACE AREA SQ.FT _____
 TEMPERATURE OF GAS: IN 122°F OUT 170-180°F
 HEATING MEDIUM SOURCE Hot Water
 TEMPERATURE & PRESSURE 325°F & 150 psig
 FLOW RATE _____ LB/HR
 REHEATER TUBES, TYPE AND MATERIAL OF CONSTRUCTION Finned tubes Carbon steel
 REHEATER LOCATION WITH RESPECT TO DEMISTER Parallel
and on top of demister
 METHOD OF CLEANING Retractable steam lance
 FREQUENCY AND DURATION OF CLEANING twice/shift
 FLOW RATE OF CLEANING MEDIUM _____ LB/HR
 REMARKS _____

6. SCRUBBER TRAIN PRESSURE DROP DATA	<u>INCHES OF WATER</u>
PARTICULATE SCRUBBER	<u>6" - 9.5"</u>
SO ₂ SCRUBBER	<u>-</u>
CLEAR WATER TRAY	<u>-</u>
DEMISTER	<u>1 - 1-1/2</u>
REHEATER	<u>1/2 - 1</u>
DUCTWORK	<u>1/2 - 1</u>
TOTAL FGD SYSTEM	<u>10" to 12"</u>

7. FRESH WATER MAKE UP FLOW RATES AND POINTS OF ADDITION

TO: DEMISTER _____
 QUENCH CHAMBER _____
 ALKALI SLURRYING _____
 PUMP SEALS _____
 OTHER _____
 TOTAL _____

FRESH WATER ADDED PER MOLE OF SULFUR REMOVED 800 GPM @
 3% S Coal 100 MW

8. BYPASS SYSTEM

CAN FLUE GAS BE BYPASSED AROUND FGD SYSTEMS Yes
 GAS LEAKAGE THROUGH BYPASS VALVE, ACFM None (liquid seal)

K. SLURRY DATA

LIME/LIMESTONE SLURRY MAKEUP TANK

PARTICULATE SCRUBBER EFFLUENT
 HOLD TANK (a)

SO₂ SCRUBBER EFFLUENT HOLD
 TANK (a)

pH	% Solids	Capacity (gal)	Hold up time
	-	-	-
	-	-	-
5.5 to 6.5	10 to 15	55000	11

L. LIMESTONE MILLING AND CALCINING FACILITIES: INDICATE BOILERS SERVED BY THIS SYSTEM.

TYPE OF MILL (WET CYCLONE, ETC.) Raymond Bowl Mill
 NUMBER OF MILLS Two (two alternate)
 CAPACITY PER MILL 13 T/HR
 RAW MATERIAL MESH SIZE 1/2" to 3/4"
 PRODUCT MESH SIZE 70% - 200 mesh

SLURRY CONCENTRATION IN MILL _____

CALCINING AND/OR SLAKING FACILITIES _____

SOURCE OF WATER FOR SLURRY MAKE UP OR
SLAKING TANK _____

M. DISPOSAL OF SPENT LIQUOR

1. SCHEMATICS OF SLUDGE & FLY ASH DISPOSAL METHOD

(IDENTIFY QUANTITIES OR SCHEMATIC) _____

2. CLARIFIERS (THICKENERS)

NUMBER one (common w/4)

DIMENSIONS 115' dia x 10' high

CONCENTRATION OF SOLIDS IN UNDERFLOW _____

3. ROTARY VACUUM FILTER

NUMBER OF FILTERS None

CLOTH AREA/FILTER -

CAPACITY - TON/HR (WET CAKE)

CONCENTRATION OF SOLIDS IN CAKE -

PRECOAT (TYPE, QUANTITY, THICKNESS) -

REMARKS -

4. SLUDGE FIXATION

POINT OF ADDITIVES INJECTION None

FIXATION MATERIAL COMPOSITION -

FIXATION PROCESS (NAME) -

FIXATION MATERIAL REQUIREMENT/TONS OF DRY SOLIDS OF SLUDGE

ESTIMATED POND LIFE, YRS. _____
CONCENTRATION OF SOLIDS IN FIXED SLUDGE _____ -
METHOD OF DISPOSAL OF FIXED SLUDGE _____ -
INITIAL SOLIDIFICATION TIME OF FIXED SLUDGE _____ -

5. SLUDGE QUANTITY DATA

POND/LANDFILL SIZE REQUIREMENTS, ACRE-FT/YR _____
IS POND/LANDFILL ON OR OFFSITE On-site _____
TYPE OF LINER None _____
IF OFFSITE, DISTANCE AND COST OF TRANSPORT _____
POND/LANDFILL DIMENSIONS AREA IN ACRES 160 _____
DEPTH IN FEET 16 _____
DISPOSAL PLANS; SHORT AND LONG TERM _____
Build new ponds as needed. May excavate existing ponds.

N. COST DATA

1. TOTAL INSTALLED CAPITAL COST 10,729,267.60 _____
2. ANNUALIZED OPERATING COST (1974) 174,022 (9 months) _____

3. COST BREAKDOWN

COST ELEMENTS	INCLUDED IN ABOVE COST ESTIMATE		ESTIMATED AMOUNT OR % OF TOTAL INSTALLED CAPITAL COST
	YES	NO	
A. CAPITAL COSTS			
SO ₂ SCRUBBER TRAINS	☒	☐	
LIMESTONE MILLING FACILITIES	☒	☐	
SLUDGE TREATMENT & DISPOSAL POND	☐	☒	
SITE IMPROVEMENTS	☒	☐	
LAND, ROADS, TRACKS, SUBSTATION	☒	☐	
ENGINEERING COSTS	☒	☐	
CONTRACTORS FEE	☒	☐	
INTEREST ON CAPITAL DURING CONSTRUCTION	☒	☐	
B. ANNUALIZED OPERATING COST			
FIXED COSTS			
INTEREST ON CAPITAL	☐	☒	
DEPRECIATION	☐	☒	
INSURANCE & TAXES	☐	☒	
LABOR COST INCLUDING OVERHEAD	☐	☒	
VARIABLE COSTS			
RAW MATERIAL	☒	☐	
UTILITIES	☒	☐	
MAINTENANCE	☒	☐	

4. COST FACTORS

- a. ELECTRICITY _____
- b. WATER _____
- c. STEAM (OR FUEL FOR REHEATING) _____
- d. FIXATION COST _____ \$/TON OF DRY SLUDGE
- e. RAW MATERIAL PURCHASING COST _____ \$/TON OF DRY SLUDGE
- f. LABOR: SUPERVISOR _____ HOURS/WEEK _____ WAGE
- OPERATOR _____
- OPERATOR HELPER _____
- MAINTENANCE _____

O. MAJOR PROBLEM AREAS: (CORROSION, PLUGGING, ETC.)

1. SO₂ SCRUBBER, CIRCULATION TANK AND PUMPS.

a. PROBLEM/SOLUTION 1) Nozzles plugged. Changed to bigger Ceramic nozzles. 2) Drain headers for post plugged. Changed to individual drain hoses. 3) Pots expanded metal taps broke loose. Used stronger tie rods and clamps. 4) pH of (A) and (B) tanks differed (5 and 9 respectively) Modifications incl. interconnecting suction of both pumps on each tank through equalizer line. 5) Sediment buildup in reaction tanks. Blinded tanks corners and installed nozzles on tank walls to improve circulation

2. DEMISTER and suspension of solids. 6) Add reactive tank mixers.

PROBLEM/SOLUTION Demisters are washed manually. Pluggage was not experienced. Scaling removed by improved washing. Added more underspray and overspray wash nozzles and lances.

3. REHEATER

PROBLEM/SOLUTION No reheater problems. Ash collects on damper during periods when bypass is open and falls on reheater tubes when bypass is closed and damper is closed. This causes slight increase in pressure drop.

4. VENTURI SCRUBBER, CIRCULATION TANKS AND PUMPS

PROBLEM/SOLUTION _____

5. I.D. BOOSTER FAN AND DUCT WORK

PROBLEM/SOLUTION Fan vibrates when restarts after
scrubber wash. Problem solved by washing of scrubber
with fan running.

6. LIMESTONE MILLING SYSTEM OR LIME SLAKING

PROBLEM/SOLUTION When used to grind limestone, the
coal ball mills have trouble; such as cracking many
rolls and wearing many balls. Problem compensated
for by readjusting roll height above bowl.

7. SLUDGE TREATMENT AND DISPOSAL

PROBLEM/SOLUTION There is no sludge treatment, and there
are no problems with sludge disposal so far.

8. MISCELLANEOUS AREA INCLUDING BYPASS SYSTEM

PROBLEM/SOLUTION Accumulation of fly ash in water seal.
Solution included installation of water flush lines
at base of seal "U" duct. Solution still needed. Different
style damper to be installed.

P. DESCRIBE FACTORS WHICH MAY NOT MAKE THIS A REPRESENTATIVE
INSTALLATION _____

Q. DESCRIBE METHODS OF SCRUBBER CONTROL UNDER FLUCTUATING
LOAD. IDENTIFY PROBLEMS WITH THIS METHOD AND SOLUTIONS.
IDENTIFY METHOD OF pH CONTROL AND LOCATION OF pH PROBES.
Control pH by regulating limestone injection. Take one
module off when load finally drops to 50 percent.

R. COMPUTATION OF FGD SYSTEM AVAILABILITY FACTOR

BOILER RATING OR MAXIMUM CONTINUOUS CAPACITY, MW 100

PERIOD MONTH/YEAR	FLUE GAS DESULFURIZATION MODULES									
	MODULE 3A		MODULE 3B		MODULE 4A		MODULE 4B			
	DOWN DUE TO		DOWN DUE TO		DOWN DUE TO		DOWN DUE TO			
	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)	BOILER (HRS)	MODULE (HRS)
January 1974	621	72	621	40	647	80	647		647	152
	528	0	528	0	314	0	314		514	8
	560	0	560	0	600	0	600		600	0
	225	0	225	0	528	0	528		582	0
	445	328	445	136	717	0	717		717	0
	277	192	277	256						
	711	328	711	352	Unit overhaul					
	650	289	650	0						
	649	134	649	104	125	0	125		125	0

Availability factor computation:

Was 30%, now for last three weeks 70%

1. Divide boiler capacity by the number of modules and obtain MW/module = x
2. Multiply boiler capacity by number of hours during period = a
3. Add all down times due to module trouble for all modules during period = b
4. Add all down times due to boiler trouble or reduction in electricity demand for all modules during period = c
5. Availability factor = $\frac{a - x}{a + b + c} \times 100 = \%$

5/17/74

UNIT NO. 4

PLANT SURVEY FORM

NON-REGENERABLE FGD PROCESSES

A. COMPANY AND PLANT INFORMATION

1. COMPANY NAME	<u>Kansas City Power & Light</u>
2. MAIN OFFICE	<u>Kansas City, Mo.</u>
3. PLANT MANAGER	<u>Verne Moore</u>
4. PLANT NAME	<u>Hawthorn Plant</u>
5. PLANT LOCATION	<u>Kansas City</u>
6. PERSON TO CONTACT FOR FURTHER INFORMATION	<u>Terry Eaton</u>
7. POSITION	<u>Results Superintendent</u>
8. TELEPHONE NUMBER	<u>471-0060 (816)</u>
9. DATE INFORMATION GATHERED	<u>6/6/74</u>
10. PARTICIPANTS IN MEETING	AFFILIATION
<u>Jerry Bennett</u>	<u>KCPL</u>
<u>Vince Palormo</u>	<u>KCPL (part time)</u>
<u>Vern Moore</u>	<u>KCPL</u>
<u>Wade Ponder</u>	<u>EPA</u>
<u>John Busik</u>	<u>EPA</u>
<u>Fouad K. Zada</u>	<u>PEDCo-Environmental</u>
<u>Larry V. Yerino</u>	<u>PEDCo-Environmental</u>
<u> </u>	<u> </u>

B. PLANT DATA. (APPLIES TO ALL BOILERS AT THE PLANT).

	BOILER NO.				
	1	2	3	4	5
CAPACITY, MW	100	100	140*	140*	500
SERVICE (BASE, PEAK)	Peak	Peak	Cyclic 25-100%	Cyclic 25-100%	Base 50-100%
FGD SYSTEM USED			x	x	

C. BOILER DATA. COMPLETE SECTIONS (C) THROUGH (R) FOR EACH BOILER HAVING AN FGD SYSTEM.

1. BOILER IDENTIFICATION NO. 4
2. MAXIMUM CONTINUOUS HEAT INPUT _____ BTU/HR
3. MAXIMUM CONTINUOUS GENERATING CAPACITY 140 MW on N.G.
100 MW on Coal
4. MAXIMUM CONTINUOUS FLUE GAS RATE, _____ ACH @ _____ °F
5. BOILER MANUFACTURER C-E
6. YEAR BOILER PLACED IN SERVICE 1955
7. BOILER SERVICE (BASE LOAD, PEAK, ETC.) Cyclic
8. STACK HEIGHT 200' (common w/3)
9. BOILER OPERATION HOURS/YEAR (1974) 5643
10. BOILER CAPACITY FACTOR ** 47.1
11. RATIO OF FLY ASH/BOTTOM ASH 4/1

* On Natural Gas (100 MW on Coal)

** DEFINED AS: $\frac{\text{KWH GENERATED IN YEAR}}{\text{MAX. CONT. GENERATED CAPACITY IN KW} \times 8760 \text{ HR/YR}}$

D. FUEL DATA

Low-Ash Hi-Ash
Typical Typical

1. COAL ANALYSIS (as received)

GHV (BTU/LB.)

S %

ASH %

MAX.	MIN.	AVG.
	9800	11400
	0.6	3
	11	14

2. FUEL OIL ANALYSIS (exclude start-up fuel)

GRADE

S %

ASH %

	-	-
	-	-
	-	-

E. ATMOSPHERIC EMISSIONS

1. APPLICABLE EMISSION REGULATIONS

a) CURRENT REQUIREMENTS

AQCR PRIORITY CLASSIFICATION

REGULATION & SECTION NO.

MAX. ALLOWABLE EMISSIONS
LBS/MM BTU

b) FUTURE REQUIREMENTS,
COMPLIANCE DATE

REGULATION & SECTION NO.

MAXIMUM ALLOWABLE EMISSIONS
LBS/MM BTU

PARTICULATES	SO ₂

2. PLANT PROGRAM FOR PARTICULATES COMPLIANCE

3. PLANT PROGRAM FOR SO₂ COMPLIANCE

F. PARTICULATE REMOVAL

1. TYPE

MANUFACTURER

EFFICIENCY: DESIGN/ACTUAL

MAX. EMISSION RATE* LB/HR

GR/SCF

LB/MMBTU

DESIGN BASIS, SULFUR CONTENT

MECH.	E.S.P.	FGD
-	-	C-E Dry Lime- ~~stone~~ injection
-	-	> 99%
-	-	
-	-	
-	-	

G. DESULFURIZATION SYSTEM DATA

1. PROCESS NAME

Dry Limestone - tail injection

2. LICENSOR/DESIGNER NAME:

Combustion Engineering

ADDRESS:

PERSON TO CONTACT:

TELEPHONE NO.:

3. ARCHITECTURAL/ENGINEERS, NAME:

ADDRESS:

PERSON TO CONTACT:

TELEPHONE NO.:

4. PROJECT CONSTRUCTION SCHEDULE:

DATE

a) DATE OF PREPARATION OF BIDS SPECS.

b) DATE OF REQUEST FOR BIDS

c) DATE OF CONTRACT AWARD

d) DATE ON SITE CONSTRUCTION BEGAN

e) DATE ON SITE CONSTRUCTION COMPLETED

f) DATE OF INITIAL STARTUP

Late Aug. 1972

g) DATE OF COMPLETION OF SHAKEDOWN

*At Max. Continuous Capacity

5. LIST MAJOR DELAYS IN CONSTRUCTION SCHEDULE AND CAUSES:

None

6. NUMBER OF SO₂ SCRUBBER TRAINS USED

2

7. DESIGN THROUGHPUT PER TRAIN, ACFM @ °F

8. DRAWINGS: 1) PROCESS FLOW DIAGRAM AND MATERIAL BALANCE

2) EQUIPMENT LAYOUT

H. SO₂ SCRUBBING AGENT

1. TYPE

Limestone

2. SOURCES OF SUPPLY

City Wide Asphalt Co.

3. CHEMICAL COMPOSITION (for each source)

SILICATES

SILICA

CALCIUM CARBONATE

MAGNESIUM CARBONATE

4. EXCESS SCRUBBING AGENT USED ABOVE
STOICHIOMETRIC REQUIREMENTS

5. MAKE-UP WATER POINT OF ADDITION

6. MAKE-UP ALKALI POINT OF ADDITION

J. SCRUBBER TRAIN SPECIFICATIONS

1. SCRUBBER NO. 1 (a) Two identical modules: Specs per module:

TYPE (TOWER/VENTURI) Rectangular Tower (18'x26'x40')
LIQUID/GAS RATIO, G/MCF @ 122 °F 21 to 26
GAS VELOCITY THROUGH SCRUBBER, FT/SEC _____
MATERIAL OF CONSTRUCTION Carbon Steel
TYPE OF LINING None

INTERNALS:

TYPE (FLOATING BED, MARBLE BED, ETC.) Marble Bed
NUMBER OF STAGES One
TYPE AND SIZE OF PACKING MATERIAL 3/4"dia. Glass Marble
PACKING THICKNESS PER STAGE ^(b) 3.5"
MATERIAL OF CONSTRUCTION, PACKING: Glass
SUPPORTS: Stainless Steel 316L

2. SCRUBBER NO. 2 (a)

TYPE (TOWER/VENTURI) _____
LIQUID/GAS RATIO, G/MCF @ °F _____
GAS VELOCITY THROUGH SCRUBBER, FT/SEC _____
MATERIAL OF CONSTRUCTION _____
TYPE OF LINING _____

INTERNALS:

TYPE (FLOATING BED, MARBLE BED, ETC.) _____
NUMBER OF STAGES _____
TYPE AND SIZE OF PACKING MATERIAL _____

a) Scrubber No. 1 is the scrubber that the flue gases first enter. Scrubber 2 (if applicable) follows Scrubber No. 1.

b) For floating bed, packing thickness at rest.

PACKING THICKNESS PER STAGE^(b) _____

MATERIAL OF CONSTRUCTION, PACKING: _____

SUPPORTS: _____

3. CLEAR WATER TRAY (AT TOP OF SCRUBBER)

TYPE _____

L/G RATIO _____

SOURCE OF WATER _____

4. DEMISTER

TYPE (CHEVRON, ETC.) Chevron

NUMBER OF PASSES (STAGES) Two

SPACE BETWEEN VANES _____

ANGLE OF VANES _____

TOTAL DEPTH OF DEMISTER 4" each (8" total)

DIAMETER OF DEMISTER 18' x 26'

DISTANCE BETWEEN TOP OF PACKING
AND BOTTOM OF DEMISTER 10'

POSITION (HORIZONTAL, VERTICAL) Horizontal

MATERIAL OF CONSTRUCTION Fiberglass

METHOD OF CLEANING 8 wash lances

SOURCE OF WATER AND PRESSURE Clarifier & make-up water

FLOW RATE DURING CLEANINGS, GPM _____

FREQUENCY AND DURATION OF CLEANING _____

REMARKS _____

5. REHEATER

TYPE (DIRECT, INDIRECT) Finned Tubes

b) For floating bed, packing thickness at rest.

DUTY, MMBTU/HR _____
 HEAT TRANSFER SURFACE AREA SQ.FT _____
 TEMPERATURE OF GAS: IN 122°F OUT 170-180°F
 HEATING MEDIUM SOURCE Hot Water
 TEMPERATURE & PRESSURE 325°F & 150 psig
 FLOW RATE _____ LB/HR
 REHEATER TUBES, TYPE AND MATERIAL OF CONSTRUCTION Finned tubes Carbon steel
 REHEATER LOCATION WITH RESPECT TO DEMISTER Parallel
and on top of demister
 METHOD OF CLEANING _____
 FREQUENCY AND DURATION OF CLEANING _____
 FLOW RATE OF CLEANING MEDIUM _____ LB/HR
 REMARKS _____

6. SCRUBBER TRAIN PRESSURE DROP DATA	<u>INCHES OF WATER</u>
PARTICULATE SCRUBBER	<u>-</u>
SO ₂ SCRUBBER	<u>-</u>
CLEAR WATER TRAY	<u>-</u>
DEMISTER	<u>_____</u>
REHEATER	<u>_____</u>
DUCTWORK	<u>_____</u>
TOTAL FGD SYSTEM	<u>10" to 12"</u>

7. FRESH WATER MAKE UP FLOW RATES AND POINTS OF ADDITION

TO: DEMISTER _____
 QUENCH CHAMBER _____
 ALKALI SLURRYING _____
 PUMP SEALS _____
 OTHER _____
 TOTAL _____

FRESH WATER ADDED PER MOLE OF SULFUR REMOVED 800 GPM @
3% S Coal 100 MW

8. BYPASS SYSTEM

CAN FLUE GAS BE BYPASSED AROUND FGD SYSTEMS Yes
 GAS LEAKAGE THROUGH BYPASS VALVE, ACFM None (liquid seal)

K. SLURRY DATA

	pH	% Solids	Capacity (gal)	Hold up time
LIME/LIMESTONE SLURRY MAKEUP TANK		-	-	-
PARTICULATE SCRUBBER EFFLUENT HOLD TANK (a)		-	-	-
SO ₂ SCRUBBER EFFLUENT HOLD TANK (a)	5.0 to 5.5	10 to 15	55000	11

L. LIMESTONE MILLING AND CALCINING FACILITIES: INDICATE BOILERS SERVED BY THIS SYSTEM.

TYPE OF MILL (WET CYCLONE, ETC.) _____
 NUMBER OF MILLS _____
 CAPACITY PER MILL _____ T/HR
 RAW MATERIAL MESH SIZE _____
 PRODUCT MESH SIZE _____

SLURRY CONCENTRATION IN MILL _____

CALCINING AND/OR SLAKING FACILITIES _____

SOURCE OF WATER FOR SLURRY MAKE UP OR
SLAKING TANK _____

M. DISPOSAL OF SPENT LIQUOR

1. SCHEMATICS OF SLUDGE & FLY ASH DISPOSAL METHOD

(IDENTIFY QUANTITIES OR SCHEMATIC) _____

2. CLARIFIERS (THICKENERS)

NUMBER One (common w/3)

DIMENSIONS 115' dia. x 10' high

CONCENTRATION OF SOLIDS IN UNDERFLOW _____

3. ROTARY VACUUM FILTER

NUMBER OF FILTERS None

CLOTH AREA/FILTER -

CAPACITY - TON/HR (WET CAKE)

CONCENTRATION OF SOLIDS IN CAKE -

PRECOAT (TYPE, QUANTITY, THICKNESS) -

REMARKS -

4. SLUDGE FIXATION

POINT OF ADDITIVES INJECTION None

FIXATION MATERIAL COMPOSITION -

FIXATION PROCESS (NAME) -

FIXATION MATERIAL REQUIREMENT/TONS OF DRY SOLIDS OF SLUDGE

ESTIMATED POND LIFE, YRS. _____

CONCENTRATION OF SOLIDS IN FIXED SLUDGE _____ -

METHOD OF DISPOSAL OF FIXED SLUDGE _____ -

INITIAL SOLIDIFICATION TIME OF FIXED SLUDGE _____ -

5. SLUDGE QUANTITY DATA

POND/LANDFILL SIZE REQUIREMENTS, ACRE-FT/YR _____

IS POND/LANDFILL ON OR OFFSITE _____

TYPE OF LINER _____

IF OFFSITE, DISTANCE AND COST OF TRANSPORT _____

POND/LANDFILL DIMENSIONS AREA IN ACRES _____

DEPTH IN FEET _____

DISPOSAL PLANS; SHORT AND LONG TERM _____

N. COST DATA

1. TOTAL INSTALLED CAPITAL COST _____

2. ANNUALIZED OPERATING COST _____

3. COST BREAKDOWN

COST ELEMENTS	INCLUDED IN ABOVE COST ESTIMATE		ESTIMATED AMOUNT OR % OF TOTAL INSTALLED CAPITAL COST
	YES	NO	
A. CAPITAL COSTS			
SO ₂ SCRUBBER TRAINS	☐	☐	
LIMESTONE MILLING FACILITIES	☐	☐	
SLUDGE TREATMENT & DISPOSAL POND	☐	☐	
SITE IMPROVEMENTS	☐	☐	
LAND, ROADS, TRACKS, SUBSTATION	☐	☐	
ENGINEERING COSTS	☐	☐	
CONTRACTORS FEE	☐	☐	
INTEREST ON CAPITAL DURING CONSTRUCTION	☐	☐	
B. ANNUALIZED OPERATING COST			
<u>FIXED COSTS</u>			
INTEREST ON CAPITAL	☐	☐	
DEPRECIATION	☐	☐	
INSURANCE & TAXES	☐	☐	
LABOR COST INCLUDING OVERHEAD	☐	☐	
<u>VARIABLE COSTS</u>			
RAW MATERIAL	☐	☐	
UTILITIES	☐	☐	
MAINTENANCE	☐	☐	

4. COST FACTORS

- a. ELECTRICITY _____
- b. WATER _____
- c. STEAM (OR FUEL FOR REHEATING) _____
- d. FIXATION COST _____ \$/TON OF DRY SLUDGE
- e. RAW MATERIAL PURCHASING COST _____ \$/TON OF DRY SLUDGE
- f. LABOR: SUPERVISOR _____ HOURS/WEEK _____ WAGE
- OPERATOR _____
- OPERATOR HELPER _____
- MAINTENANCE _____

O. MAJOR PROBLEM AREAS: (CORROSION, PLUGGING, ETC.)

1. SO₂ SCRUBBER, CIRCULATION TANK AND PUMPS.

- a. PROBLEM/SOLUTION Problems similar to those of
Unit 3. See survey form of Unit 3 for details.
- _____
- _____
- _____
- _____

2. DEMISTER

PROBLEM/SOLUTION Problems similar to those of Unit 3.

3. REHEATER

PROBLEM/SOLUTION Problems similar to those of Unit 3.

4. VENTURI SCRUBBER, CIRCULATION TANKS AND PUMPS

PROBLEM/SOLUTION _____

5. I.D. BOOSTER FAN AND DUCT WORK

PROBLEM/SOLUTION Problems similar to those of Unit 3.

6. LIMESTONE MILLING SYSTEM OR LIME SLAKING

PROBLEM/SOLUTION Problems similar to those of Unit 3.

7. SLUDGE TREATMENT AND DISPOSAL

PROBLEM/SOLUTION Problems similar to those of Unit 3.

8. MISCELLANEOUS AREA INCLUDING BYPASS SYSTEM

PROBLEM/SOLUTION Problems similar to those of Unit 3.

P. DESCRIBE FACTORS WHICH MAY NOT MAKE THIS A REPRESENTATIVE INSTALLATION

Q. DESCRIBE METHODS OF SCRUBBER CONTROL UNDER FLUCTUATING LOAD. IDENTIFY PROBLEMS WITH THIS METHOD AND SOLUTIONS. IDENTIFY METHOD OF pH CONTROL AND LOCATION OF pH PROBES.

Control pH by regulating limestone injection. Take one module off when load finally drops to 50 percent.

BOILER RATING OR MAXIMUM CONTINUOUS CAPACITY, MW _____

Availability factor computation:
Unit did not run long enough
to have availability factor.

- 5/17/74

APPENDIX B
PLANT PHOTOGRAPHS

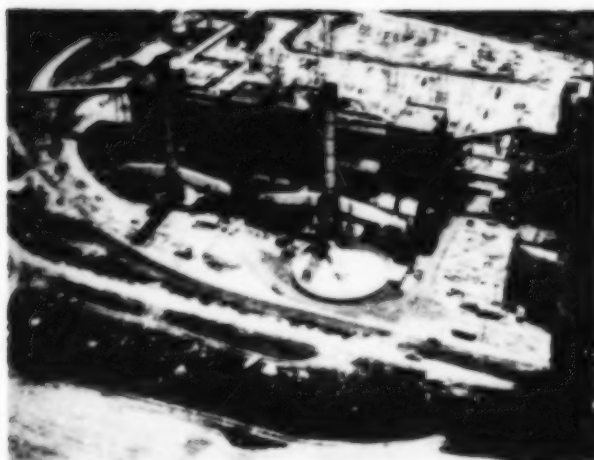


Photo No. 1 Bird's eye view of the Hawthorn Power Station. Boilers 1 and 2 are on the left, and boilers 3 and 4 are at the center with part of Boiler No. 5 shown at the right side of the picture. The sludge clarifier tank is in front of Boiler No. 4.

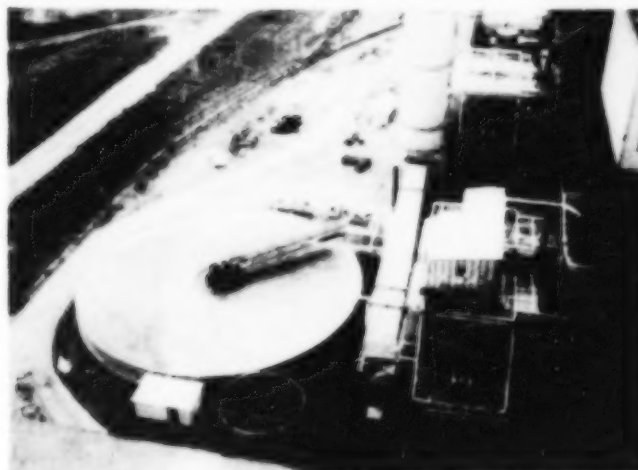


Photo No. 2 General view of the FGD systems on Boilers 3 (in the background) and 4 (in the foreground). The clearwell tank which holds the clarifier's overflow water is shown near the clarifier tank. Make-up water to the system (which is Missouri River water) is further clarified in the clarifier tank.

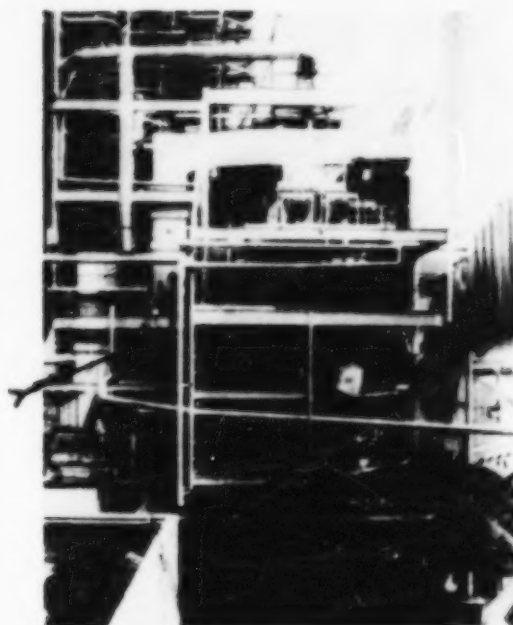


Photo No. 3 Side view of FGD module 4B on boiler No. 4. The bypass water seal in the ductwork around the module is indicated by an arrow.

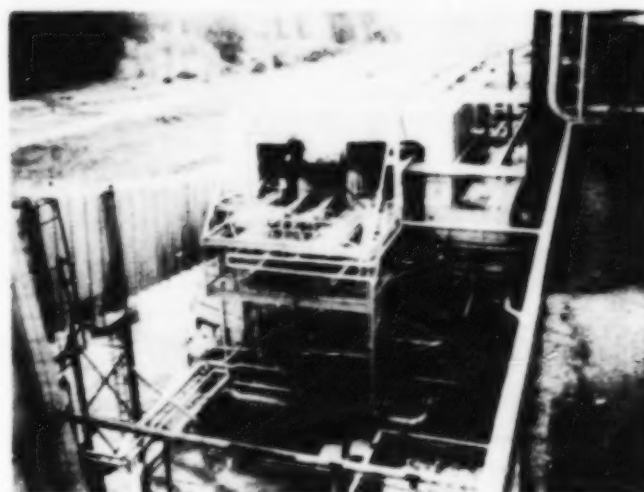


Photo No. 4 Side view of FGD module 3B as seen from the structure of boiler No. 4. The two steam lances for cleaning of the reheater tubes are shown on the top level. The demister water lances are located on the level below.



Photo No. 5 View of the piping network which is used for injection of dry limestone in the flue gas ductwork to the two modules on boiler No. 4. The isolation valves can be seen in the pipes leading to each module.



Photo No. 6 Front view of the two FGD modules on boiler No. 3. Showing the two I.D. fans and the common ductwork to the stack.

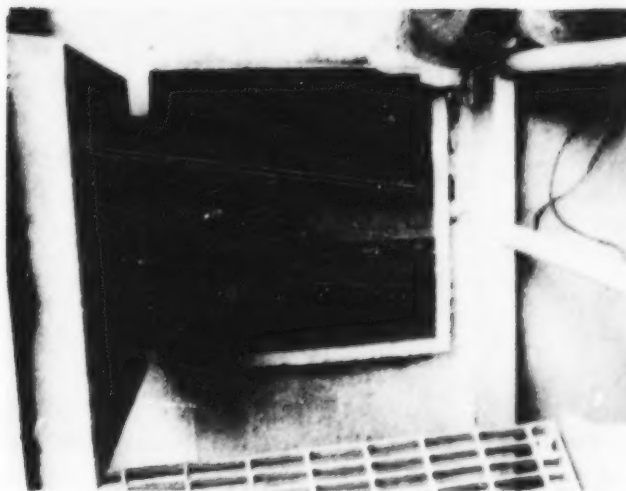


Photo No. 7 View of the top of the demister on module 3B as seen through the inspection window. One of the Chevron vanes support beams is shown in the center.

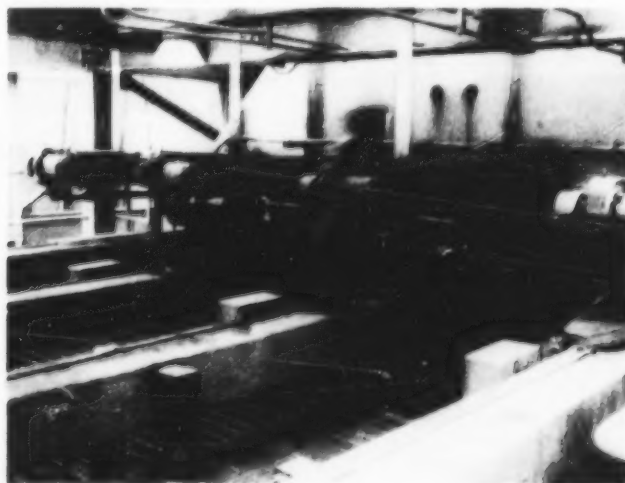


Photo No. 8 Close up view of the 8 water lances on module 3B. These lances are used to wash the demister. The top four are of the rotary type and are located between the two layers of demisters. The bottom four lances are of the retractable type and they provide the underspray wash water.

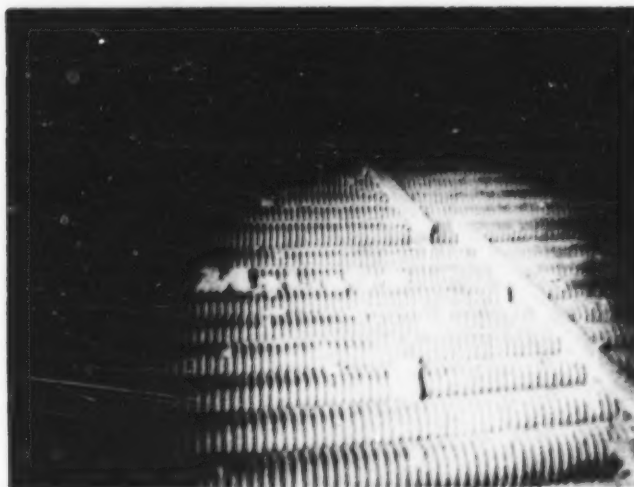


Photo No. 9 Picture taken through the reheater inspection window showing the top of the reheater finned tubes. The gravel-like objects on top of the tubes are broken pieces of fly ash mud. These accumulate on the bypass damper during the periods when the module is out of service, and fall down on the tubes when damper is reopened.



Photo No. 10 Close up view of the driving mechanism of the retractable steam lances on module 3B.

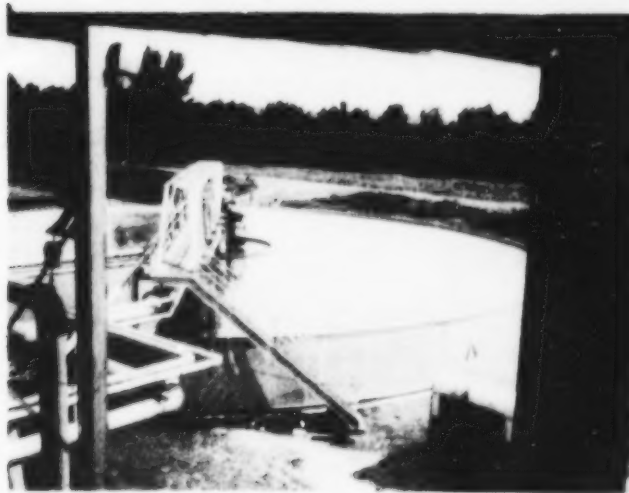


Photo No. 11 View of the 115 ft-diameter clarifier tank as seen from the structure of module 4A. The overflow from this tank empties in a small clearwell tank (now shown) located to the left of the clarifier. The fresh make-up water to the clarifier tank is pumped from the Missouri River which flows near the trees in the background.

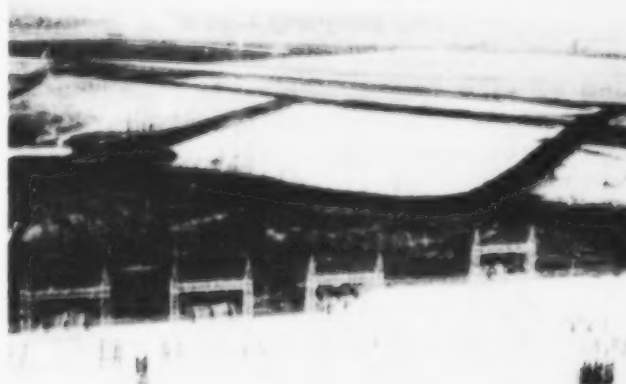


Photo No. 12 View of the fly ash and limestone sludge pond as seen from the structure of boiler No. 5. The feed to this pond is from the underflow of the clarifier tank.